For larger systems that are being built to meet Duke's "designated" and "mandated" programs, I recommend Duke assume that 100% of future builds will be single-axis trackers. The cost premium of tracking systems has declined over time, and as shown by the market evolution, the additional energy and capacity benefits that come from trackers more than compensates for the price premium.

I also recommend that Duke remove the 500 MW limit from its base case and instead model the higher 900 MW limit from its high renewables sensitivity. Duke's own plans will require much higher levels of interconnection in the future, making it imperative that the Company pursue changes that will allow higher rates now.

### *F. Duke's Development Timeline for SMR and Pumped Hydro Resources is Inconsistent with Its Own Data*

**Q86. WHAT ASSUMPTIONS DOES DUKE HAVE RELATED TO THE AVAILABILITY OF SMRS?**

A86. Duke assumes that SMRs will be utilized in two of its six portfolios. The first, "70% $CO_2$ Reduction: High SMR" assumes that 1,368 MW of SMR capacity will be online by 2029. The second, "No New Natural Gas", assumes 684 MW of SMR capacity will be online by 2035.[102]

**Q87. WHAT ASSUMPTIONS DOES DUKE HAVE RELATED TO PUMPED HYDRO?**

A87. Duke assumes that a 1,620 MW of new pumped hydro capacity will be online in 2034 in three portfolios: both 70% $CO_2$ reduction portfolios and the No New Natural Gas portfolio.

**Q88. WERE THESE RESOURCES SELECTED AS PART OF THE MODELING OPTIMIZATION PROCESS?**

A88. No. These resources were not selected through the modeling optimization process, but rather added manually after the fact in each of these portfolios.[103]

**Q89. DID DUKE PROVIDE OTHER INFORMATION RELATED TO THE DEVELOPMENT TIMELINE OF SMR PROJECTS?**

[102] Exhibit KL-13, Duke Response to SCSBA RFP 2 (producing Duke response to DR PSDR 3-14).
[103] Exhibit KL-14, Duke Response to SCSBA RFP 2 (producing Duke response to DR NSCEA 7-3).

A89. Yes. Duke provided this information in response to a question when SMRs are assumed to be online:

> SMRs modeled for the IRP have eight (8) year capital spend, with the first two (2) year [sic] primarily focused around licensing, and the final six (6) year [sic] being construction, testing, and commissioning. As stated in the IRP, the company recognizes the challenges with integrating a first of a kind technology in a relatively compressed timeframe are significant. Therefore, these cases are intended to illustrate the importance of advancing such technologies as part of a blended approach that considers a range of carbon-free technologies to allow deeper carbon reductions.[104]

In other words, Duke would have to begin activities related to SMR deployment this year in order for these units to be online in 2029. Given this case will not be decided until the middle of 2021, and Duke is not requesting approval to build an SMR in its IRP, Duke's own development timelines are incompatible with its assumption that SMR capacity would be online in 2029.

**Q90. Are there any active SMR projects in development that can provide insight to this challenge?**

A90. Yes. There is a project under development by Nuscale in Idaho that had secured offtake agreements from a number of municipal utilities in Utah. Nuscale spun out of Oregon State University in 2007 and began development of the SMR. The project proposes using twelve 60 MW SMRs to form a single 720 MW facility housed at the Department of Energy's Idaho National Laboratory.

Last fall, after another round of project delays and cost increases pushed the cost estimate from $4.2 billion in 2018 to $6.1 billion in 2020, several of the municipal utilities exited their positions.[105] The project recently received $1.4 billion in financial support from DOE to help keep the eventual price of power from the SMR to under $55/MWh, the maximum amount provided by the agreement with the municipal utilities.[106]

[104] Exhibit KL-2.

[105] https://www.utilitydive.com/news/design-updates-financial-shakeup-prompt-utilities-to-rethink-structure-of/589262/.

[106] https://www.energy.gov/ne/articles/doe-approves-award-carbon-free-power-project.

Even with this financial support from DOE and having been under development for more than a decade, the facility has not yet received its design certification from the Nuclear Regulatory Commission, although it did pass a key milestone in receiving its safety evaluation report in August 2020. Nonetheless, Nuscale plans to begin construction by December 2025 and have the first module in service by 2029, the same year Duke contemplates a fully-operational SMR facility.[107]

**Q91. DID DUKE PROVIDE OTHER INFORMATION RELATED TO THE DEVELOPMENT TIMELINE OF PUMPED HYDRO?**

A91. Yes. Duke provided a confidential study performed by [redacted] in [redacted] for [redacted] regarding potential greenfield locations for additional pumped storage located on or about [redacted][108] This study included cost estimates for [redacted] sites and an environmental, regulatory, and licensing analysis on new pumped hydro. The key details for these projects are shown in Table 5 below.

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**Q92. WHAT WAS THE DEVELOPMENT SCHEDULE ASSOCIATED WITH THESE FACILITIES?**

A92. [redacted] projected a 13-year development timeline for each of the facilities. This included eight years of engineering, environmental, and regulatory studies followed by five years of

[107] https://www.sciencemag.org/news/2020/11/several-us-utilities-back-out-deal-build-novel-nuclear-power-plant.
[108] Exhibit KL-15, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-36).
[109] Converted using BLS CPI Inflation Calculator, available at https://www.bls.gov/data/inflation_calculator.htm.

construction. Based on this schedule, for these units to be online in 2034, development would have to begin in 2021. Given this case will not be decided until the middle of 2021, and Duke is not requesting approval to build pumped hydro capacity in its IRP, Duke's own development timelines are incompatible with its assumption that new pumped hydro capacity would be online in 2034.

**Q93. WHAT IS YOUR CONCLUSION REGARDING THE INCLUSION OF SMR AND PUMPED HYDRO IN SOME OF DUKE'S PORTFOLIOS?**

A93. Based on Duke's own assessments, the timelines projected for SMR and pumped hydro are unattainable. While Duke admits that some of its portfolios are "intended to illustrate the importance of advancing such technologies", it is unfortunate that all three of Duke's deep-decarbonization portfolios rely on resources that, based on Duke's own assumptions, are not likely to be deployed in time to attain the carbon reduction. The Commission should request that Duke construct a deep-decarbonization portfolio that does not require resources with unachievable development timelines, but rather focuses on more robust deployment of existing resources such as solar, wind, and storage.

## IV. DUKE'S NATURAL GAS PRICE FORECAST AND SENSITIVITES ARE FLAWED AND BIASED DOWNWARD

**Q94. WHY IS THE NATURAL GAS PRICE FORECAST AND YOUR CRITIQUE OF IT SO CRITICAL TO FULLY UNDERSTANDING DUKE'S IRP FILING, ITS PORTFOLIO CONSTRUCTION, AND THE RISK ASSESSMENT OF THOSE PORTFOLIOS?**

A94. The natural gas price forecast is one of the most important input assumptions in Duke's modeling. This input impacts how Duke's modeling selects between resources as it optimizes capacity additions across the IRP planning horizon. In the model, Duke enters the IRP planning period with substantial coal capacity and generation, with 18% of capacity and 16% of total generation coming from coal under the Base case with Carbon Policy.[110] By 2035, most of the coal has been retired, and the amount still operating only produces 1% of total generation. How this coal capacity and energy will be replaced is the fundamental question of this case and mirrors the broader evolution of the electricity sector across the country.

Duke's model currently favors natural gas over renewables and storage to replace the retiring coal, as demonstrated by the small amounts added by the model optimization under the two base cases.[111] However, this modeling outcome is not a reflection of the merits of natural gas over renewables, but is instead a mathematical result of the model's assumptions. Further, this mathematical result is heavily influenced by the natural gas price forecast that Duke uses, which is in turn based on low market prices from the illiquid portion of the natural gas futures price curve. By exclusively using ten years of market prices, and relying on those same forecasts for five more years, the model is biased towards building and running natural gas assets. This means that natural gas CC units built in 2027 and 2028 clears out the capacity need for many years to follow, which, under Duke's modeling set up, prevents any more capacity from being built.

But this modeling relies on flawed inputs. A natural gas forecast based more on fundamentals-based forecasts and less on volatile market prices is not only more robust but also presents the model with higher natural gas prices during the critical mid-2020s through mid-2030s period, when the first capacity needs arise. Under this scenario, the economics of building and operating natural gas CCs and CTs will be relatively more expensive than deploying renewables and storage, and the model optimization may reach a very different result that instead is weighted towards zero-carbon renewables and storage.

This has a meaningful impact on the relative riskiness of Duke's portfolios. Duke has already acknowledged the need to transition away from fossil fuels. However, its modeling

[110] DEC IRP Report at 107.

[111] The model does not select any solar in the Base case without Carbon Policy beyond what Duke manually added, and only selects 25% of the total solar in the Base case with Carbon Policy.

assumptions, driven in large part by its natural gas forecast, result in the addition of massive quantities of natural gas generation well into the future. In fact, Duke's Base case with Carbon Policy shows generation from natural gas CCs growing from 21% in 2021 to 31% in 2035, only to be bolstered further by additional CCs past 2035.[112] It has not adequately analyzed the risk associated with firm fuel supply and costs or potential carbon policy in the future, must less reconciled these new gas plants with its 2050 net-zero goal.

Simply put, Duke's flawed natural gas forecast leads to portfolios that are heavily weighted towards natural gas generation instead of ones based more on renewables and storage. If Duke were to follow this path, it would unnecessarily expose its customers and its shareholders to substantial and avoidable risk.

**Q95. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR TESTIMONY.**

A95. For the reasons discussed above, I have developed extensive testimony that walks the reader from Duke's construction of its forecast through the likely final impacts of its choice. I detail Duke's methodology of using market prices for ten years before fully switching to a fundamentals-based forecast by year sixteen in constructing its natural gas forecast and high- and low-price sensitivities. I draw a straight line from the lack of liquidity in the futures market to the lack of robust long-term price formation for the specific financial instrument Duke used to establish the market prices. I also show that long-term futures prices primarily reflect short-term volatility rather than being reflective of the macroeconomic dynamics that influence long-run prices. I then discuss the flaws in Duke's approach to producing its high- and low-price sensitivity, before concluding with observations about the potential collective impact of these choices on Duke's IRP modeling that may have resulted in more natural gas and less solar and storage resources being added in the future.

**Q96. WHAT ARE YOUR PRIMARY CONCLUSIONS?**

[112] DEC IRP Report at 107.

A96. Duke's natural gas forecast is highly problematic. It begins with a flawed assumption that its ability to purchase *de minimis* quantities of natural gas on ten-year contracts justifies its decision to base the first ten years of its model entirely on market prices. I show how prices from the financial instrument it used to secure the gas supply are directly derived from futures contracts, and how the prices for those futures contracts beyond two years are based on almost no market transactions.

I then show how near-term price volatility in the natural gas futures market works its way into the long-term portion of the futures price curve. As part of this analysis, I show the sizable week-to-week volatility that occurred in 2020 meant that if Duke had locked in its gas forecast a few weeks earlier or a few weeks later, it would have produced a meaningfully different result.

The fact that a key input like the first ten years of natural gas prices is so exposed to short-term volatility is a clear sign that it should not be relied upon for more than a few years. To counter this, I propose an alternative forecast methodology that would smooth the short-term volatility in the market prices and only rely on them exclusively for 18 months before transitioning over 18 months to a fundamentals-based forecast.

Next, I discus the methodology that Duke used to construct its high- and low-price sensitivities. Because the Company's method is entirely based on the short-term price volatility of futures contracts, extrapolating out ten years produces a "random walk" result that deviates substantially from fundamentals-based forecasts. The resulting sensitivities contain disjointed segments that would require a bizarre sequence of massive policy shifts to bring to fruition.

Finally, I discuss how Duke's natural gas price forecast might have impacted its IRP results and why it is critical that the modeling be updated with better assumptions. These forecasts impact asset selection, PVRR, and carbon emissions, and play a key role in the risk assessment that Duke should have produced between its several portfolios. Leaving this many outcomes dependent on a flawed natural gas price forecast is highly inappropriate.

### A. *Duke's Use of Market Prices for Ten Years is Inappropriate*

**Q97. How was Duke's natural gas price forecast developed?**

A97. Duke based its forecast on "market prices" from financial instruments that were prices based on natural gas futures contracts for years 1 through 10, transitioned linearly to a fundamentals-based forecast from years 11 to 15, before utilizing a fundamentals-based forecast from year 16 forward. The Company also developed a high- and low-price sensitivity, applying a statistical methodology to market prices before transitioning to two Energy Information Administration (EIA) Annual Energy Outlook (AEO) fundamentals-based forecast scenarios.[113] The resulting annualized forecast is shown below in Figure 14. This is a recreation of Figure A-2 from the DEC IRP Report and clearly delineates the three disjointed sections of 100% market prices and 100% fundamentals-based forecast, joined by the five-year transition between the two.

[113] DEC IRP Report at 157-158.

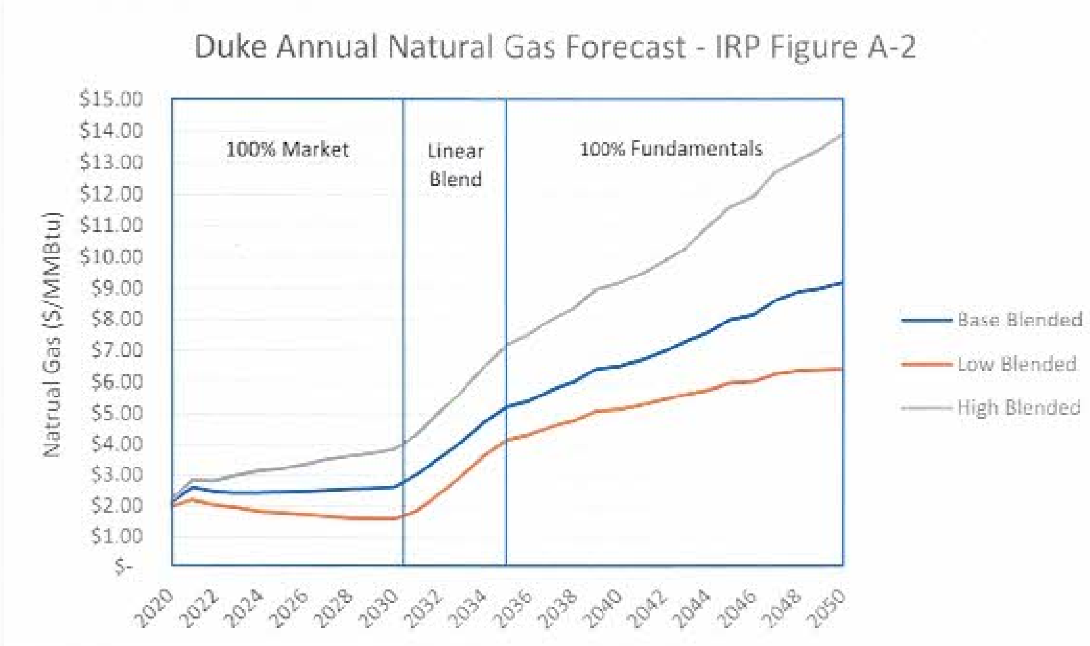


*Figure 14 - Duke Annual Natural Gas Forecast - IRP Figure A-2*

**Q98. WHAT MARKET PRICE DOES DUKE USE IN ITS FORECAST?**

A98. Duke uses market prices based on a 116-month fixed price swap for 2,500 dts/day for May 2020 through December 2029.[114] The fixed-price swap (or swap) is a financial derivative that allows market players to hedge their future purchases or sales of a commodity by locking in a fixed price now rather than facing the market price in the future. For a purchaser of natural gas such as Duke, buying a swap allows it to lock in its natural gas fuel price in the future and reduces the risk associated with market price fluctuations. If the market price in the future is higher than the swap price, then Duke will save money, but if it is lower, it will lose money. That said, the point of hedging in general is not to speculate on the future price of natural gas (there are other ways to accomplish that), but to reduce risk of Duke's financials associated with natural gas price fluctuations.

The monthly price of the swap is based on another financial product called a futures contract (also referred to as just futures). These contracts are financial instruments between

[114] Exhibit KL-16, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 5-3).

two parties (a buyer and a seller) that gives the buyer the right to receive and obligates the seller to deliver a certain quantity of natural gas at a certain price at a certain place in the future.[115] For example, one can purchase a futures contract that would give the buyer the right to receive 10,000 MMBtu of natural gas in July 2024 at Henry Hub at $2.433 / MMBtu.[116] If in July 2024 the spot price (i.e. the then-current market price) for natural gas is $3.00 / MMBtu, the holder of the futures contract would have the right to receive it from the seller for $2.433 / MMBtu for gas rather than the higher market price.

Swaps and futures are different but related products. Futures contracts are standardized (same quantity, same delivery location) and settle through the NYMEX exchange and obligate physical delivery or receipt of a product. Swaps, by contrast, can be customized to meet the requirements of the buyer or seller, such as changing the location of delivery, and can be purchased through brokers or through commodities exchanges.

**Q99. WHAT IS A FUNDAMENTALS-BASED FORECAST?**

A99. A fundamentals-based forecast uses a model that simulates entire sectors of the economy to determine supply, demand, and prices for commodities. The EIA AEO uses the National Energy Modeling Systems ("NEMS") model for this purpose. EIA describes NEMS as

> a computer-based, energy-economy modeling system for the United States. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics.[117]

**Q100. WHAT IS THE DIFFERENCE BETWEEN PRICES FROM NATURAL GAS FUTURES CONTRACTS AND SWAPS AND THOSE FROM A FUNDAMENTALS-BASED FORECAST?**

[115] Futures rarely result in physical delivery of the product. Instead, holders of the contracts typically close their positions prior to physical delivery.
[116] https://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_globex.html.
[117] *The National Energy Modeling System: An Overview 2018*, available at https://www.eia.gov/outlooks/aeo/nems/overview/pdf/0581(2018).pdf.

A100. Much like equities in the stock market, futures prices are affected by market participants buying and selling contracts and by factors such as weather or policy changes that may affect future natural gas supply and demand. Futures prices can be very volatile and reflect the short-run impacts of factors such as weather and natural gas storage capacity. Futures are also used by produces or consumers of natural gas to hedge their planned natural gas sales or purchases and can be traded by anyone simply looking to speculate on expected changes in price. All of these factors, including purchases by companies like Duke and commodities speculators halfway around the world, impact the price of these financial derivatives.

By contrast, a fundamentals-based forecast such as AEO eliminates much of the short-term noise from commodities traders and weather, focusing instead on the underlying factors and policies that drive long-term behavior. AEO contains numerous policy scenarios that determine how prices will respond to, for example, the introduction of a carbon price or federal clean energy legislation, or a sudden increase or decrease in the availability of natural gas or oil at low prices. These changes filter through the entire model, meaning that the supply, demand, and prices that emerge reflect the holistic result of the fundamentals, not short-term trends driven by weather or trading activity.

**Q101. How robust are the futures market prices?**

A101. The robustness or "efficiency" of market prices[118] is heavily driven by a market's liquidity; illiquid markets or products that have few trades and low volume are less robust and produce less efficient prices than liquid markets with many participants. The most popular natural gas future is the Henry Hub Natural Gas ("NG") future found on the NYMEX exchange.[119] While there is considerable volatility in the price of these contracts, as the third-largest physical commodity futures contract in the world by volume, it is very liquid – for some time periods.

**Q102. What do you mean "for some time periods"?**

[118] In this context, efficient pricing is one that incorporates sufficient relevant information that allows buyers and sellers to make informed decisions about the value of the assets they are trading.
[119] https://www.cmegroup.com/trading/energy/nymex-natural-gas-futures.html#tab1.

A102. Trading exchanges list two metrics of market activity: volume and open interest. Volume reflects the total amount of activity in a day (i.e. the total number of contracts that were bought or sold) while open interest reflects the total number of contracts that are outstanding (i.e. how many open contracts exist between buyers and sellers). The NG future offers monthly prices for the current year and next 12 calendar years, meaning that one can in theory lock in the price for delivery of natural gas between next month and December 2033. However, the overwhelming majority of market activity is constrained to contracts less than a year in the future, and there is almost no market activity for contracts more than two years in the future.

**Q103. WHY IS THAT IMPORTANT?**

A103. It is important because higher market activity leads to more accurate price formation, and conversely, low market activity leads to poor price formation. Imagine a saleswoman is selling a blue widget and wants to know what its value is to purchasers. If the saleswoman asks only one person what they would pay for it, the answer may be dependent on somewhat random factors such as whether that person liked the color blue or if they already had a widget. If she happened to ask a prospective customer who liked blue, the perceived value of the widget may be higher than if she happened to ask someone who preferred red. But if the saleswomen asks 100 people, or 1,000 people, or 1,000,000 people, more information can be incorporated into the price and the saleswoman will have a much better sense of how much customers will pay for the widget.

**Q104. EXACTLY HOW LITTLE MARKET ACTIVITY EXISTS IN NATURAL GAS FUTURES BEYOND TWO YEARS?**

A104. The market activity drops substantially as one moves into the future.[120] Figure 15 below shows the cumulative trading volume of all NG futures contracts averaged over the days of January 20, 2021 to February 2, 2021. On those days, 77% of all volume was for futures contracts no

[120] Market activity obtained from CME Group at https://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_globex.html.

more than six months in the future, 94% for contracts up to a year out, and 99.1% for contracts up to eighteen months out. There was no trading at all for contracts past May 2024.

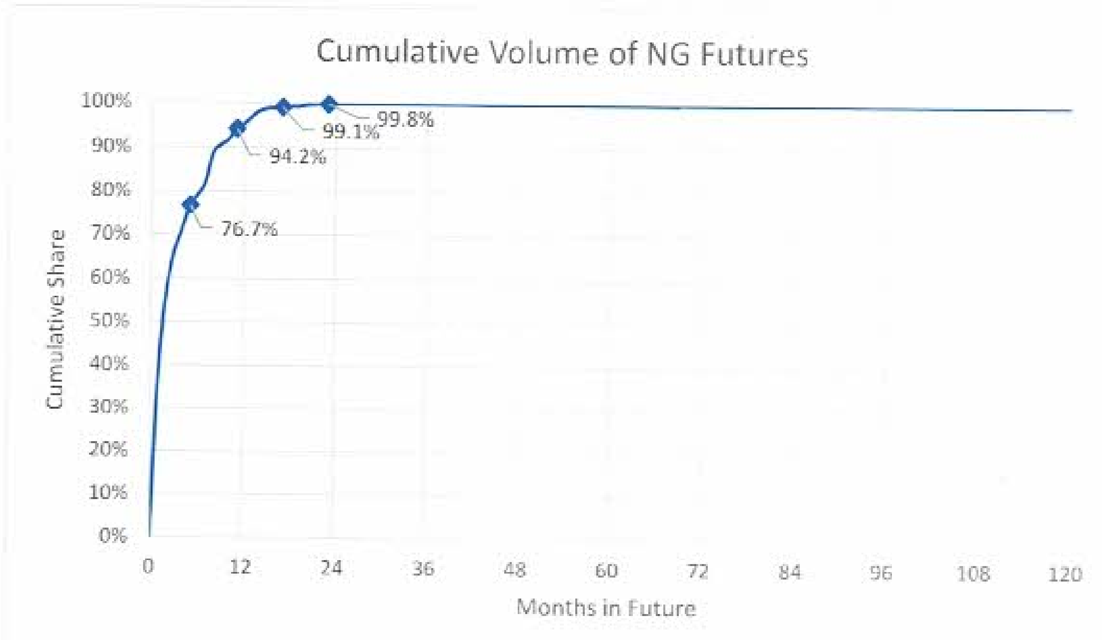


*Figure 15 - Cumulative Volume of NG Futures*

Figure 16 below shows a similar chart but for open interest. The curve is slightly flatter, with 86.2% of open interest for contracts within one year and 98.1% for contracts within two years. Only 0.083% of all open interest in the most liquid natural gas exchange in the world is for contracts from January 2026 and beyond. To put that in perspective, the number of open contracts in the next 12 months is roughly equal to 85% of the natural gas volume used by the entire U.S. electricity power sector in 2019. By contrast, the total number of open contracts from January 2026 through December 2033 would only be enough to power a single 1,200 MW NGCC plant for two and a half months.[121] This paltry volume does not support robust price formation.

[121] As of closing on 1/28/21, there were 973,194 open contracts of 10,000 MMBtu each for March 2021 through February 2022. This is equal to 9,732 bcf. According to EIA, the U.S. electricity power sector used 11,287 bcf of natural gas in 2019. On that same day, there was a total of 1,317 open contracts for January 2026 through December 2033. In a typical 7,000 heat rate NGCC unit, this would produce 1,881 GWh, the same amount from running the plant for 78 days.

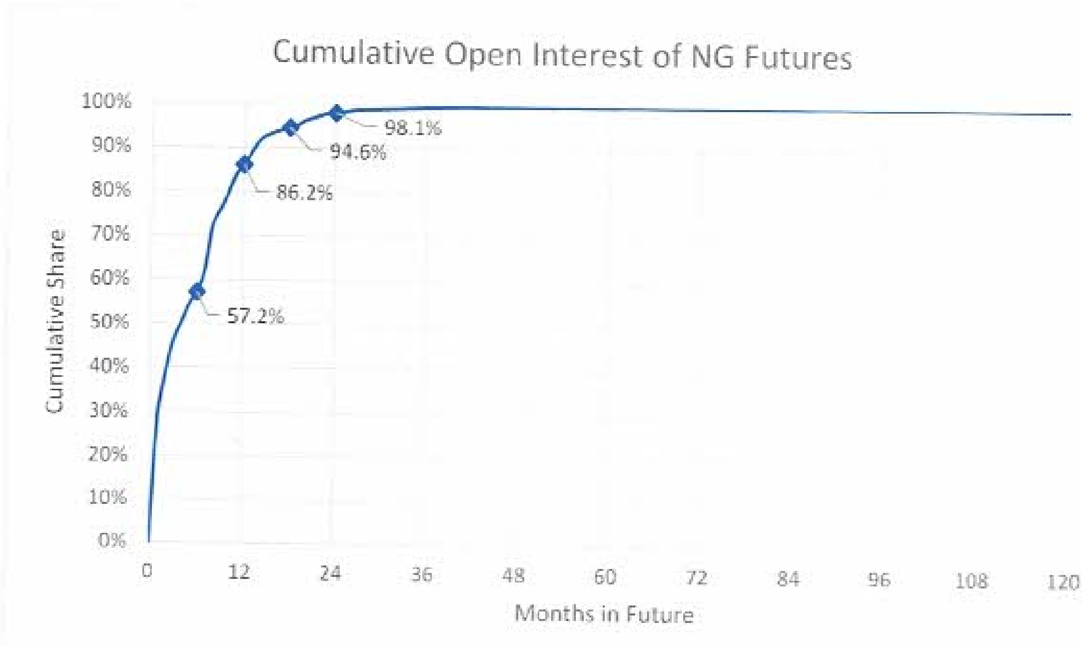


*Figure 16 - Cumulative Open Interest of NG Futures*

**Q105. DOES THIS LACK OF LIQUIDITY IN THE LONG-TERM FUTURES MARKET TRANSLATE INTO SWAPS?**

A105. Yes, it does. While swaps are not the same product as futures, they are priced based on futures contracts with potential incremental charges for brokers fees or risk premiums. This relationship is clear when one inspects the price of Duke's swap with the corresponding futures contract from that day, as shown in Figure 17 below. The prices of the two instruments are ,in the swap in the out years.

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Because of this, the lack of liquidity in the market for futures more than five years out becomes embedded in the price of a swap. So while Duke may be able to procure small amounts of natural gas through 10-year swaps, it does not mean that the prices on which they are based have been robustly set by the market.

**Q106. DUKE HAS ARGUED THAT ITS ABILITY TO PURCHASE SMALL AMOUNTS OF GAS ON A TEN-YEAR FORWARD BASIS DEMONSTRATES THE MARKET IS SUFFICIENTLY LIQUID TO RELY ON ITS PRICES.[122] HOW MUCH NATURAL GAS SUPPLY DID DUKE SECURE IN THE SWAP DISCUSSED ABOVE?**

A106. It procured 2,500 decatherms/day, equal to 2,500 MMBtu per day. In a natural gas combined cycle unit with a typical heat rate of 7,000, this is sufficient to generate about 357 MWh per day or 130 GWh per year. Considering that DEC and DEP combined have forecasted sales of

[122] See e.g. Reply Comments of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Docket No. E-100, Sub158 at 17. Available at https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=7c33d58d-fc8e-47ac-8f27-d96222e3ec38.

154,228 GWh in 2020, the natural gas fuel needed to supply 0.08% of Duke's annual generation secured the swap is simply *de minimis*.[123]

If Duke wishes to use market prices for up to ten years in its gas forecast, it should obtain market quotes from reliable brokers for a meaningful quantity of gas to see if they are available and at prices comparable to small purchases. For instance, it would be instructive to see the price to purchase 50% of Duke's projected natural gas consumption from for the next ten years on a fixed price contract. If there is even a counterparty willing to sell this contract, it will likely contain a price premium that makes it substantially more expensive what Duke has demonstrated through relatively tiny purchases.

**Q107. DOES DUKE ACTUALLY LIMIT ITS USE OF MARKET PRICES TO TEN YEARS?**

A107. No. Despite what Duke claims in its IRP report, it is using market prices to define or influence its natural gas forecast for a full 15 years. Duke relies entirely on market prices for the first 10 years of its forecast. Only after this point does it switch linearly from the market prices to the fundamentals-based forecast. So while the influence of market prices diminishes each year after year 10, it continues to impact the final forecast until year 16.[124]

**Q108. DID DUKE OBTAIN MARKET PRICES FOR THIS FULL 15 YEARS?**

A108. No, it did not. The market prices from the 10-year swap stop in December 2029. Monthly futures available on April 9, 2020, the date when Duke locked in its natural gas market price forecast and its high- and low-price forecasts, only went through December 2032.[125] To extend these prices to 2035, Duke simply applied the "year-over-year growth from the last year of market data."[126] The complete lack of market data available for prices this far in the future should preclude Duke from applying any weight whatsoever to market prices past twelve years to its natural gas forecast.

[123] 2020 IRP_ Model Inputs_NON-CONFIDENTIAL.
[124] DEC IRP Report at 157.
[125] Exhibit KL-17, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-35).
[126] Exhibit KL-17.

### B. *Futures Prices are Highly Volatile and Incorporate Short-Term Volatility into Long-Term Prices*

**Q109. HOW ARE PRICES IN THE NATURAL GAS MARKET BEST DESCRIBED?**

A109. They are best described as highly volatile. The natural gas industry is a sprawling, complex sector of the economy. Natural gas is used not only by the electric sector for electricity generation but used heavily in residential and commercial buildings for space and water heating and by industry as feed stocks for many products. Production, transmission, and storage of natural gas involves an entire other set of market participants, and there is a vibrant commodity market where traders and speculators seek profits on natural gas financial derivatives.

Demand for natural gas is highly dependent on weather and storage capacity, leading to major swings in prices during extreme weather events that affect demand or natural disasters that impact supply. Because the market is affected by myriad factors, many of which are unknowable more than a few days out, daily prices are highly volatile. Figure 18 below shows the daily Henry Hub spot price from 1997 through 2021.[127] Major events such as Hurricane Katrina in 2005, Hurricane Ike in 2008, and the Polar Vortex in 2014 can be clearly seen through their impact on prices.

[127] https://www.eia.gov/dnav/ng/NG_PRI_FUT_S1_D.htm.

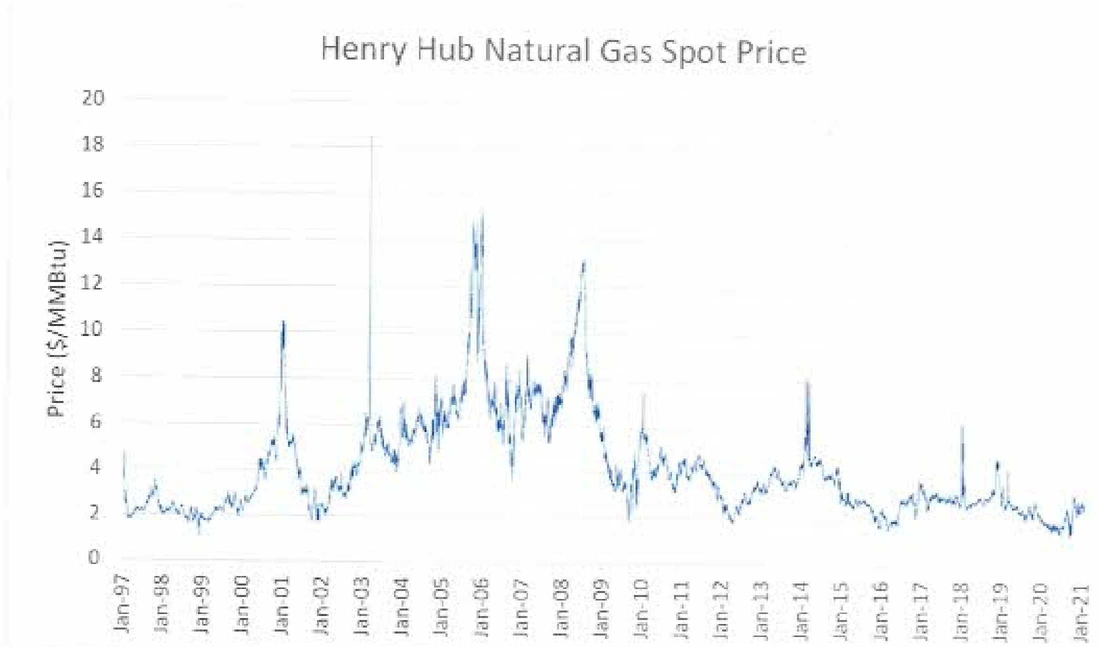


*Figure 18 - Henry Hub Natural Gas Spot Price*

This volatility in prices and corresponding futures contracts can be analyzed and visualized. EIA maintains a data set of Henry Hub spot prices and corresponding futures contracts for one, two, three, and four months in the future back to 1997.[128] Figure 19 below shows the ratio of the future contract price to the eventual spot price for each month.[129] While some periods have been more volatile than others, there have been few if any periods where the futures price ended up aligned with spot prices. In times of extreme volatility, futures prices for four months in the future can easily be more than 40% higher or lower than the spot price.

[128] https://www.eia.gov/dnav/ng/NG_PRI_FUT_S1_D.htm.

[129] The values associated with January 2020 show the ratio of the price of the January 2020 future contract from December 2019 ("M+1"), November 2019 ("M+2") October 2019 ("M+3"), and September 2019 ("M+4") divided by the January 2020 spot price.

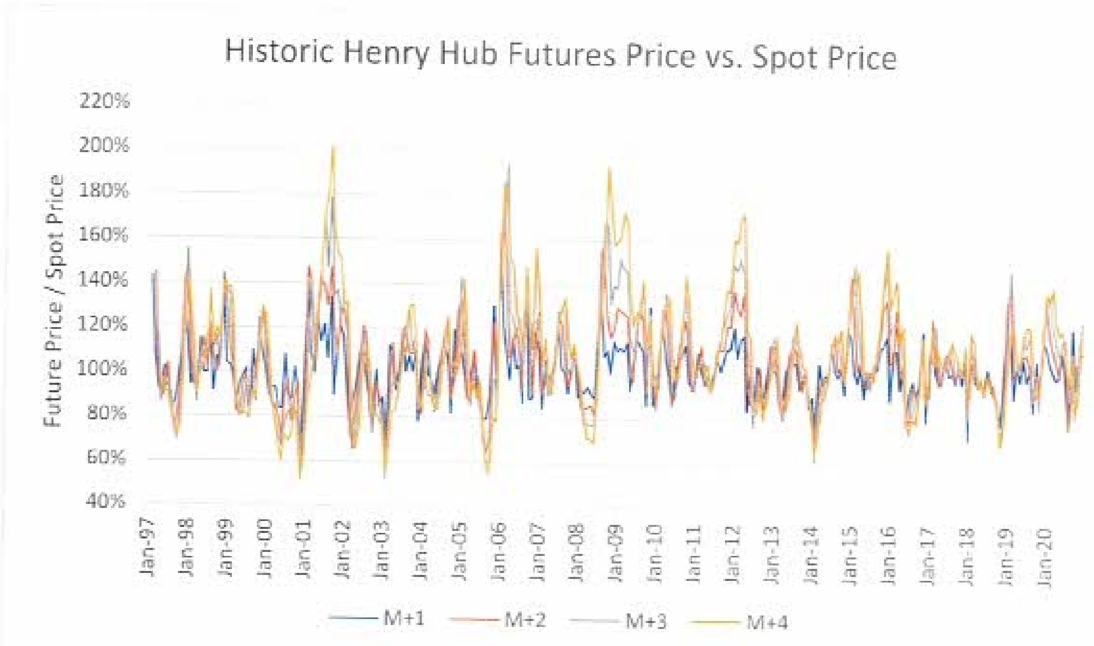


*Figure 19 - Historic Henry Hub Futures Price vs. Spot Price*

**Q110. IS THIS VOLATILITY LIMITED TO THE NEAR-TERM?**

A110. No. The price volatility of futures spans the time horizon of offered contracts, although the price swings are most pronounced for contracts in the subsequent 12 months. Figure 20 below shows changes to the daily settlement curve for futures from January 20, 2021 through January 28, 2021.[130]

[130] Data obtained from CME Group at https://www.cmegroup.com/ftp/settle/.

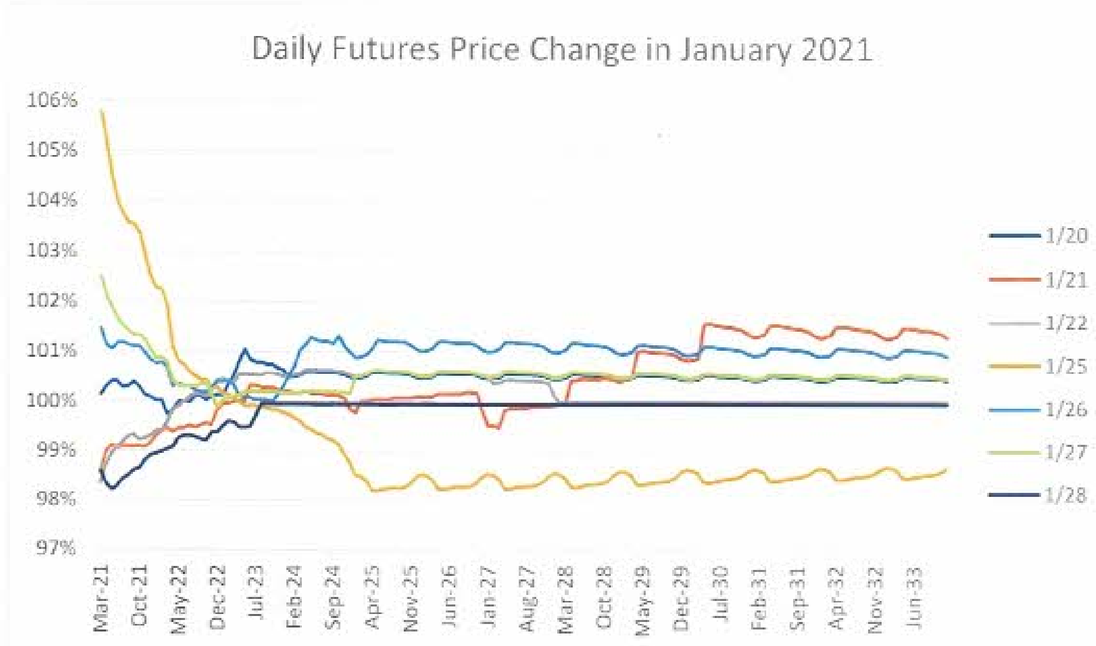


*Figure 20 - Daily Futures Price Change in January 2021*

The lack of liquidity's impact on price formation is clearly delineated in this chart. Daily changes for near-term futures on the left side of the graph show sizable, variable, and continuous changes from month-to-month, reflecting the higher volume of trades across those contracts. By contrast, the daily changes past January 2024 are almost always constant step-changes of 0.5% increments overlaid with small seasonal variations. For instance, the yellow line representing the change from 1/24/21 to 1/22/21 (the previous market day) reduced out-year contract prices by roughly 1.5% from 2025 through 2033. The very next day, the light blue line showing the change from 1/25/21 to 1/26/21 increased prices by roughly 1% from 2024 forward.

There is no rational underlying explanation for why the price of natural gas between four and twelve years in the future would suddenly and uniformly drop by 1.5% in a day only to rise suddenly and uniformly 1% the next day. And yet these types of daily moves are common, despite a complete dearth of daily policy changes that in theory could drive long-term shifts in supply and demand in the physical natural gas market that affect prices. Because of this arbitrary shifting, if Duke had obtained its 10-year swap on 1/25/21 instead of 1/22/21, its long-term price forecast would have been 1.5% lower for the duration of the IRP planning horizon.

### C. *The Price Volatility Around Duke's Forecast Lock In Timing Highlights the Flaw of Using Futures for Long-Term Pricing*

**Q111. DO THESE PRICE SWING TRENDS PERSIST OVER LONGER TIME FRAMES?**

A111. Yes. While I do not have bulk access to daily historical futures price settlement data, I was able to extract the price of certain contracts at several dates over the past 18 months. Figure 21 below is a graph of the weekly price of a January 2022 futures contract going back to 2010.[131] When this future was first offered, the long-term forecasts for natural gas were suggesting much higher prices. As the fracking boom occurred and supply was increased, the price of the futures contract fell. Notice that while the January 2022 contract price followed the long-term downward trend consistent with new natural gas supply, major swings still occurred back in 2010 through 2012 that were not supported by the trading volume that was present over the past year (indicated by the bars in the lower-right corner of the graph).

[131] https://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_globex.html.

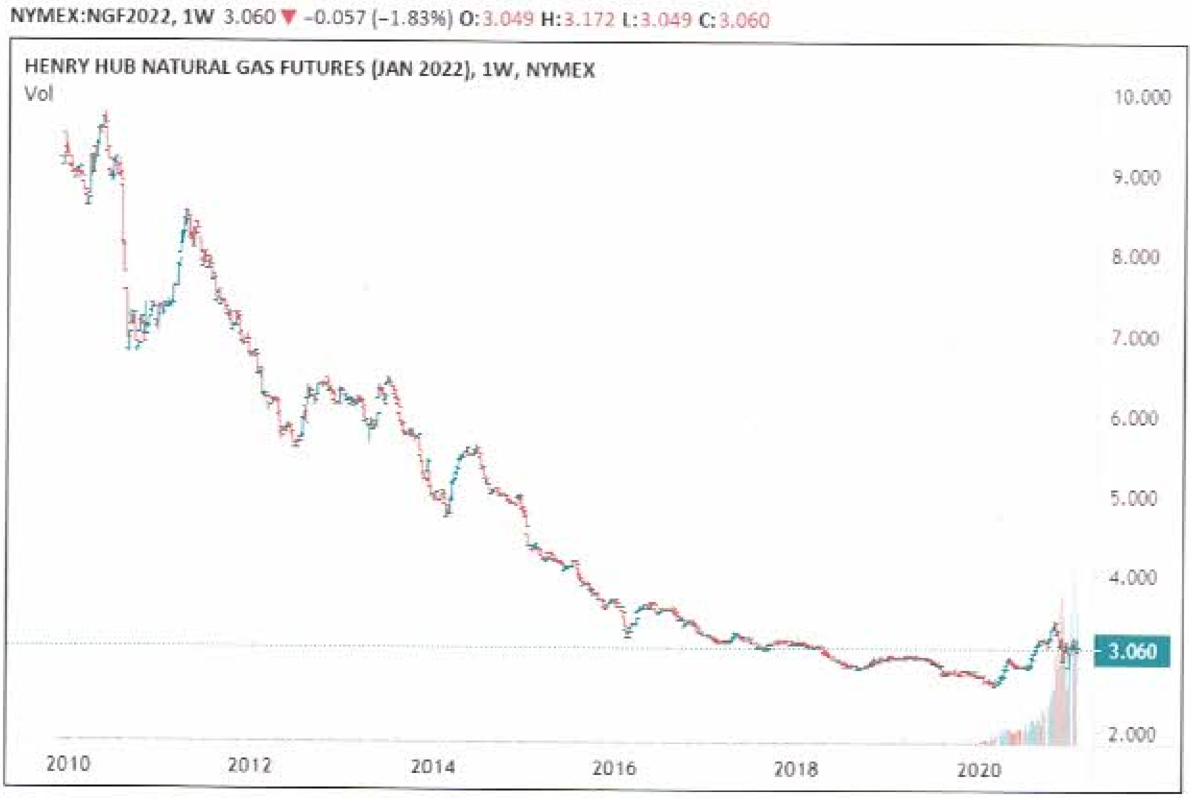


*Figure 21 - January 2022 Futures Contract Weekly Price History*

While Figure 21 above represents the price of only one futures contract for January 2022 as it evolved over time, Figure 22 below is a complex chart showing the price history of the January futures contracts from 2022 through 2030, with 2022 in blue, and 2023 through 2030 in progressively lighter shades of green.[132] I have also included small inset charts that show the futures price curve on specific dates, demonstrating the relationship between the spacing of lines on the main chart and that day's futures curve shape (high or low, inclined or flat).[133]

[132] This chart can be interpreted as snapshots of the shape of the futures curve graph that has price on the y axis and time on the x axis.

[133] The futures price curve is a chart with price on the y axis and time on the x axis. The inset charts represent the price of January forwards that were available on those dates.

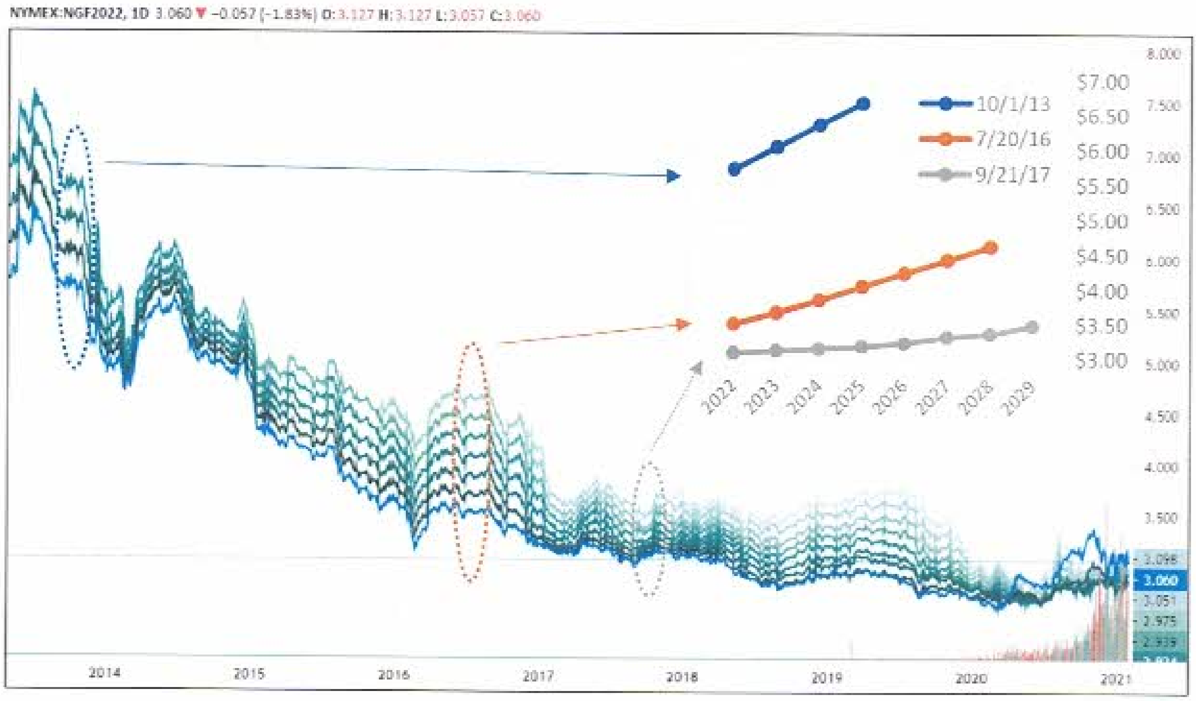


*Figure 22 - Evolution of Natural Gas Futures Prices 2013-2021*

On its own, this chart is somewhat difficult to interpret, but two key observations emerge. First is that for most of the past ten years, the graph of the futures prices had an upward-sloping trajectory. This is visible in the higher prices for successive years showing up in order of color. Sometimes, such as in 2013, the lines are further apart, indicating a steeper upward slope. Other times, such as in the summer of 2014, they are closer together, indicating a flatter slope. Second, the overall curve has fallen in absolute value over time, from in the $5.00 - $6.00 per MMBtu range in 2014 to the $2.75 - $3.75 per MMBtu range in 2019, reflecting the long-term increase in supply brought on by the fracking boom.

**Q112. HAS THIS CONSISTENT, UPWARD-SLOPING FUTURES CURVE PERSISTED INTO THE RECENT PAST?**

A112. No. Beginning in 2020, the dynamics of the futures contract market changed. Figure 23 below zooms in on the past eighteen months of data. The left side of the chart from summer 2019 mirrors the historic trends, with an upward sloping futures curve, albeit at lower absolute levels than in prior years. However, 2020 has broken from the past trends. The futures curve has moved around substantially, sometimes inverting (where short-term prices (blue) are higher than long-term prices (green)) only to quickly revert back weeks later.

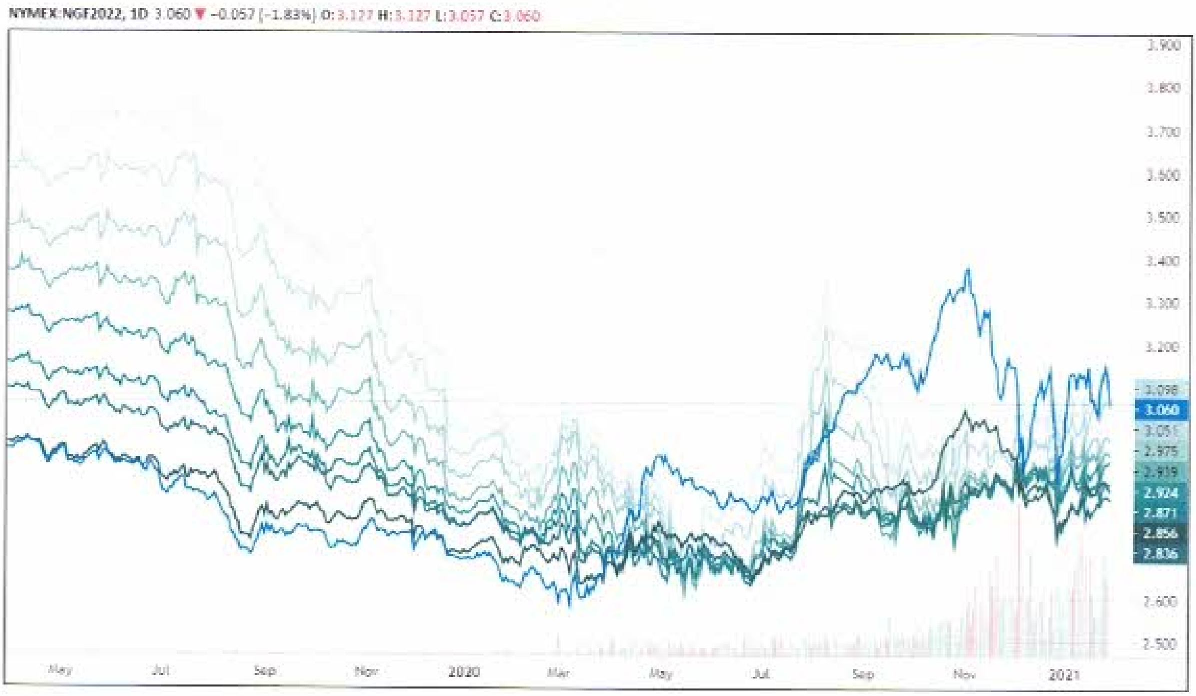


*Figure 23 - Evolution of Natural Gas Futures Prices 2019 - 2021*

The rapid movement of the futures curve in 2020 means that the market prices that form the first ten years of Duke's natural gas price forecast were locked in at a time when volatility was at a recent high. Figure 24 below shows the January futures contract prices for 2022 through 2030 for selected dates in the past 10 months.[134] On March 9, 2020, the futures curve was still sloped steadily upward. By April 9, 2020, the front portion of the curve had inverted, while the out years' price had fallen roughly 7%.[135] A bit more than a month later, on May 14, 2020, the inversion deepened, and long-term prices fell further.

[134] January contracts typically have the highest prices of the year and are used as a proxy for the underlying fuel price over time.

[135] April 9, 2020 was the date that Duke used to establish its natural gas market price forecast and its high and low natural gas price forecasts. Exhibit KL-17.

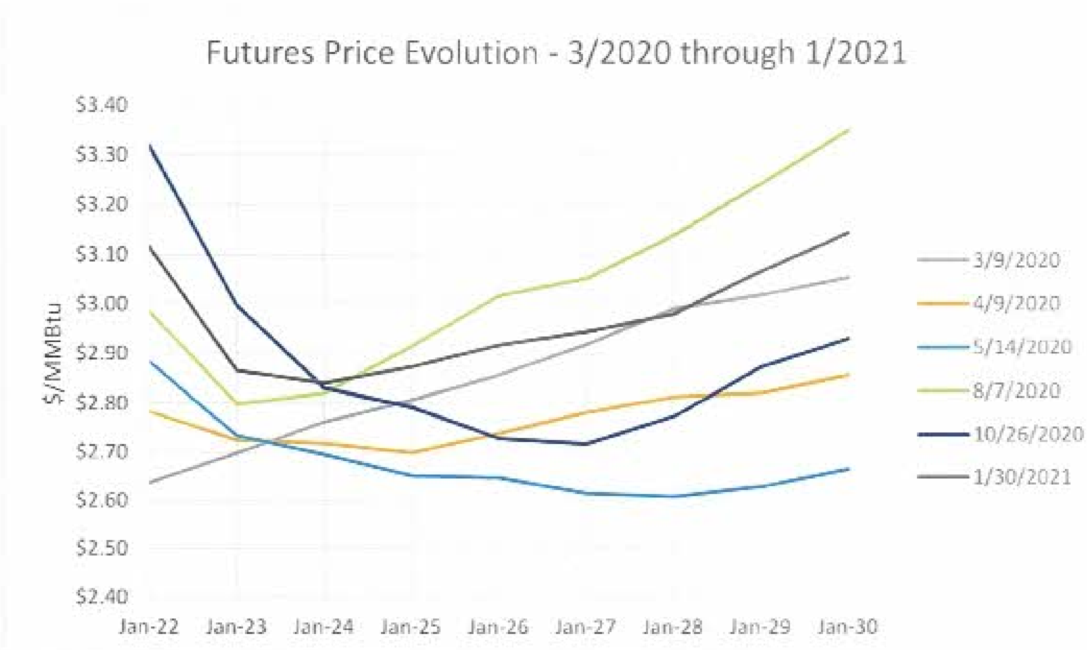


*Figure 24 - Futures Price Evolution - 3/2020 through 1/2021*

But this position was not held for long. By August 7, 2020, there had been a steep climb of the curve, with the inversion gone for all but 2022 and 2030 prices rising more than 25% from their May lows. By the end of October 2020, the curve shifted dramatically again; the inversion was back and stronger than any time in the previous year. Finally, at the end of January 2021, the inversion shifted again, with near-term prices falling while long-term prices rose.

**Q113. DO THESE RAPID AND MAJOR SHIFTS IN THE FUTURES CURVE SIGNAL CORRESPONDINGLY MAJOR SHIFTS IN THE FUNDAMENTAL DYNAMICS OF THE NATURAL GAS MARKETS?**

A113. No. The fluctuations in 2020 are most likely due to short-term supply, demand, and storage constraints combined with the sizable uncertainty due to COVID working their way into long-term forecasts. This is similar to what was shown above in Figure 20, where out-years had identical changes from day to day. If one strings together enough consecutive days of hot summer weather or mild winter weather expectations on top of the rapidly evolving coronavirus situation, the 0.5% daily changes can add up.

But to suggest that the fundamentals of the U.S. natural gas that drive long-term supply and demand jerked up and down in 2020 to this degree is to misstate the nature of "fundamentals". Figure 25 below shows a simplified version of Figure 23 above with only a few selected dates. The darker green lines represent near-term contracts while the lighter represent long-term contracts.

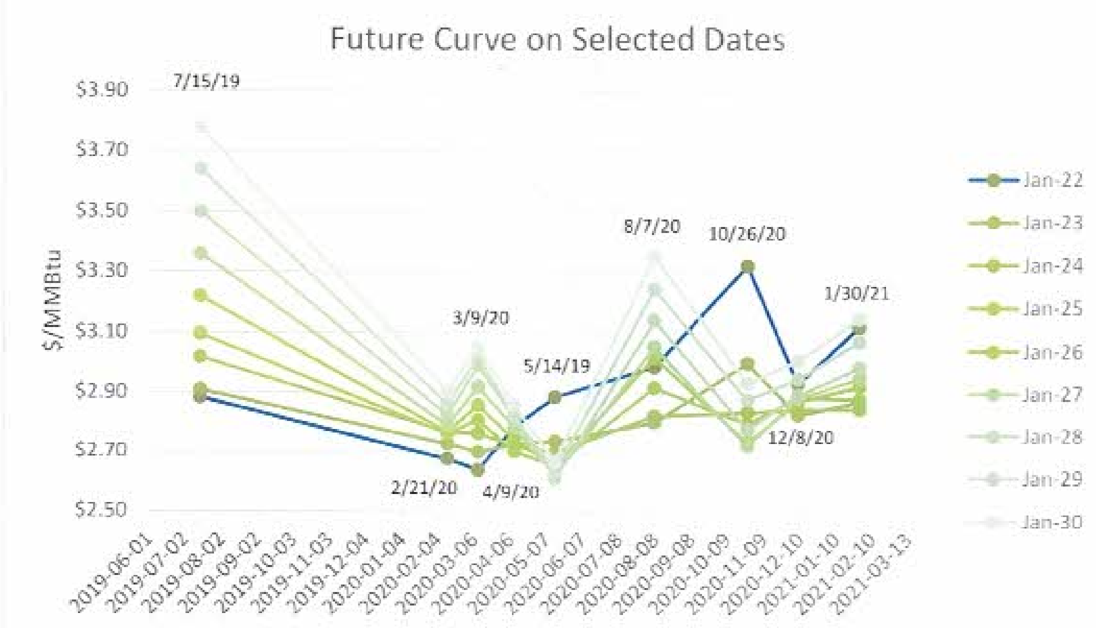


*Figure 25 - Future Curve on Selected Dates*

**Q114. WHAT DOES THIS MEAN FOR DUKE'S NATURAL GAS FORECAST?**

A114. Duke locked in its market price forecast for natural gas and its high- and low-price natural gas price sensitivities on April 9, 2020, right in the middle of a major period of volatility in futures markets, and very near to the lowest price point in the market in several years. Had the swap been priced a bit earlier or later, the natural gas prices for the first 15 years of the IRP would have been substantially different, potentially producing substantially different IRP results as well. Figure 26 below shows the percent change in the January futures contracts on certain dates compared to Duke's annual market price forecast.

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[redacted]

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If Duke had locked in prices a month earlier, its gas price forecast from 2025 through 2030 would have been [redacted]% to [redacted]% higher, a non-trivial amount. If they locked in prices a month later, the prices would have been [redacted]% to [redacted]% lower. If they had refreshed their forecast in the summer, prices could have been [redacted]% to [redacted]% higher. These are not small variations, nor can they be considered forecast sensitivities. They are simply the result of relying too long on highly volatile prices from financial derivatives to establish or influence prices for all 15 years of the IRP planning horizon.

Nor can this issue be blamed on the strange and hopefully-not-repeated circumstances of 2020 and the COVID crisis. As shown in Figure 22 above, there have been plenty of times in the past when the entire futures curve shifted up or down substantially in a short period. For instance, early 2016 saw prices falls rapidly only to recover a few months later, and early 2017 featured a substantially flattening of the futures curve over the span of weeks.